A Report of the Electric Power Survey Committee of the EDISON ELECTRIC INSTITUTE

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1985 ELECTRIC POWER ANNUAL REPORT

HISTORY: 1981-85 □ PROJECTIONS: 1986-95

A REPORT OF THE ELECTRIC POWER SURVEY COMMITTEE OF THE EDISON ELECTRIC INSTITUTE

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Figure 1/U.S. REGIONS OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

IDENTIFICATION OF RELIABILITY COUNCILS:

ECAR—East Central Area Reliability Coordination Agreement
ERCOT—Electric Reliability Council of Texas
MAAC—Mid-Atlantic Area Council
MAIN—Mid-America Interpool Network
MAPP—Mid-continent Area Power Pool
NPCC—Northeast Power Coordinating Council
SERC—Southeastern Electric Reliability Council
SPP—Southwest Power Pool
WSCC—Western Systems Coordinating Council

The electric utility systems of the United States are normally operated as three separate interconnected areas: the Eastern Interconnection, the Electric Reliability Council of Texas (ERCOT), and the Western Systems Coordinating Council (WSCC). Generating capacity available in one of these areas is not usually available to any other area. Also, generating capacity in one of the interconnected areas may not be available to serve load throughout that area due to various internal constraints.

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FOREWORD

This third issue in the new format (introduced with the 1983 Electric Power Annual Report) presents information concerning the electric power supply, expansion of electric generating facilities, and the manufacture of heavy electric power equipment in the United States as of the end of 1985.

The report is divided into three parts. Part I covers the history of electric power supply from 1981 through 1985. Part II pertains to projected power supply values from 1986 to 1995. Part III has to do with the planned domestic manufacture and importation of heavy electric power equipment as of January 1, 1986.

The historical data from 1981 through 1985 are an accurate presentation of the peak load, capability installed to meet load, and energy requirements for these time periods. The electric power supply data shown in Parts I and II of this report are derived from IE-411 reports for previous years submitted to the Department of Energy and to the North American Electric Reliability Council (NERC). Historical capability values have all been revised to agree with installed capability figures provided to NERC headquarters by the reliability councils. Forecast values used herein were obtained from IE-411 reports and from the advance release of ELECTRIC POWER SUPPLY & DEMAND 1986-1995 published by NERC in June of 1986. Installed capability, peak load and percent capacity margin values shown in this report for the summer of 1985 update the preliminary actual values published in EEI's 1985 Post-Summer Electric Power Survey. In conformity with NERC's practice, projected peak load values are not reduced by the amount of interruptible contracts.

Data in this report represent the total electric utility industry of the contiguous United States, including Investor-Owned systems and those of governmental agencies – Federal, Municipal and State & Local – and also Rural Electric Cooperatives.

The reported data include some industrial power installations whose operations are coordinated with the utility systems with which they are interconnected and which thereby contribute to the public supply. The data do not include any isolated industrial or institutional power installations.

Data pertaining to power system capabilities, peak loads, percent capacity margins, and energy requirements are presented for each of the nine reliability councils of NERC. Boundaries of the nine reliability councils are shown by the map in Fig. 1. The North American Electric Reliability Council encompasses essentially all utility systems in the United States and five Canadian provinces, but the data presented in this report cover only the systems in the contiguous United States.

Part III of this report presents the results of the semi-annual survey on manufacture and scheduling of heavy electric power equipment made as of January 1, 1986, by the Statistics Department of the Edison Electric Institute in cooperation with representatives of the electric utility industry throughout the contiguous United States, with the nation's principal manufacturers of heavy electric power equipment, and with those foreign manufacturers supplying electric generating equipment to U.S electric power systems.

The Edison Electric Institute is the only organization servicing the electric utility and allied industries that conducts surveys on the manufacture and scheduling of heavy electric power equipment on a semi-annual basis. These surveys are also unique in that information on each planned project is cross checked with both the manufacturer and the system ordering the equipment. Furthermore, the time frame for ordered and scheduled units is not limited to ten years, but extends into the future as far out as equipment is officially ordered and scheduled for installation. The resulting data file also allows the semi-annual tracking of unit slippages and cancellations.

Projections presented in this report are based on the best information available from the turn of the year through the end of the first quarter of 1986. There could, however, be delays in the installation of scheduled capacity and reductions in the percent capacity margins. This may occur, for example, due to the inability of utilities to secure the financing or the regulatory approvals necessary to sustain the construction of new generating capacity. It is essential that the installation of both nuclear and coal-fired generating units proceed as currently scheduled and that conservation and load management programs be pursued at the same time to assure an adequate bulk electric power supply into the 1990s.

Definitions of the terms used in this report, together with information concerning methods of summarizing the data, appear on the following page.

DEFINITIONS AND METHODS OF SUMMARIZATION

INSTALLED CAPABILITY is the maximum load which a generating unit or a group of units can carry under specified conditions for a given period of time. Installed capability values are shown in the historical summer and winter tables.

CAPABILITY, as projected in this report, is equivalent to Planned Resources, defined by the North American Electric Reliability Council to include the total installed generating capacity which is existing, presently under construction, or in various stages of planning; plus scheduled capacity purchases, less scheduled capacity sales; less total generating capacity out of service in deactivated shutdown status. This capability must provide for the projected load plus scheduled maintenance, forced outages, system operating requirements, and any unforeseen load. The capabilities of all systems normally interconnected are based upon fully coordinated operation. Peak capability refers to the maximum capability, as defined above, at the approximate time and for the duration of the load referred to, that is, at the time of the summer peak load or the winter peak load. Regional capability, as reported herein, is the sum of the capabilities of the systems serving the region.

PEAK LOAD for a region may be either coincident or non-coincident. It is the sum of the actual or projected peak load of the electric utilities and any self-generating industrial facilities.

HISTORICAL AND PROJECTED INSTALLED MARGIN shown on the summer and winter tables represents the difference between Installed Capability and Peak Load. It is the margin available to replace generating equipment out of service due to planned scheduled maintenance, forced outages, and equipment deratings due to various causes. In addition, Installed Margin must provide an Operating Reserve to cover variations in peak load, and to regulate frequency and control transmission tie-line schedules.

PERCENT CAPACITY MARGIN is the installed margin divided by capability multipled by 100.

CAVEATS Because some maximum regional loads may occur in winter rather than in summer, the installed margin for the country as a whole is not necessarily valid with respect to the electric power situation at that time.

It is also true that regional installed capacity margins [and hence the installed margin for the sum of the regions] in summer or winter have not always represented the minimum or the maximum margin. The extremes of installed capacity margins may be influenced, for example, by the date of bringing new large generating facilities into commercial operation in relation to the time of the annual peak loads -- the addition of a very large generating unit just before the peak could give a larger margin during the peak period than that which existed before the time of peak. Also, in areas having high proportions of hydroelectric generating capacity, the lowest margins may occur at times other than when the load is at a maximum because of low capability resulting from minimum water for power generation.

The adequacy of electric generating capability cannot be judged solely by an inspection of the installed capacity margin. The Edison Electric Institute does not collect the data necessary for a proper presentation or review of this question. This may involve consideration of monthly load characteristics, the impact of planned and forced outages of generating equipment and the possibility of load variations due to uncertain weather conditions and economic activity. There have been several occasions within the past 15 years when the entire installed margin has been utilized to offset outages of generating equipment, with consequent system-wide voltage reductions, interruption of interruptible loads, public appeals, and some interruption of firm customer load.

LOAD FACTOR is the ratio of the megawatthour output supplied during a designated period to the output that would have occurred had the peak experienced during that period been constant throughout the period. In other words, Annual Percent Load Factor is calculated by multiplying annual megawatthour requirements by 100 and dividing by the product of the annual peak load and the number of hours in a year (8,760 in normal years, 8,784 in leap years).

TOTAL U.S., as used in this publication, is equivalent to the lower forty-eight contiguous states; Alaska and Hawaii are omitted.

AVERAGE ANNUAL COMPOUND GROWTH RATES are calculated on a point-to-point basis, either by taking the fourth root of the difference between the values for the first and fifth historical years in Tables 1, 2, and 4, or the ninth root of the difference between the first and tenth projected years in Tables 10, 11, and 13.

CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

INDUSTRY PERFORMANCE IN 1985

During the year 1985, the electric power systems of the contiguous United States placed 16.6 thousand megawatts of additional electric generating capacity into commercial operation. This includes all units of 4 megawatts capacity and larger. Of this total, 26 units with capability ratings aggregating 3,176 megawatts are hydraulic, and 26 units totaling 13.5 thousand megawatts are thermal. Seven of the thermal units were powered by nuclear fuel, and 15 were conventional steam turbine-generators. The individual generating units that make up the 16.6 thousand megawatts added during 1985 are identified in the actual additions listing on page 15.

This newly added capacity contributed to the increase in the total capability, or load-carrying ability, of the U.S. electric power systems to 636.5 thousand megawatts at the year end – an increase of 2.3 percent over the total at the end of 1984.

Of the total capability of 636.5 thousand megawatts, approximately 87 percent is thermal and the rest hydraulic. During the past five years, the total capability of the country's electric power systems has increased at an average annual rate of 2.1 percent.

The combined 1985 summer peak load, shown in Table 1 of this report, was 460.5 thousand megawatts or 0.9 percent higher than the 1985/86 winter peak load. This is the twenty-second consecutive year during which the combined summer peak load exceeded the peak of the following winter. The point-to-point compound average annual increase between the 1981 and 1985 summer peak loads was 1.8 percent.

Table 2 shows that the combined winter 1985/86 peak load of the contiguous United States was 423.7 thousand megawatts – 2.9 percent higher than the winter 1984/85 peak load. The change in peak load during the past five years, from winter 1981/82, was a net increase of 25.9 thousand megawatts, and is equivalent to an average annual increase of 1.6 percent on a point-to-point compounded basis.

As can be seen from Table 4, during 1985 the energy requirements for the contiguous United States amounted to 2.5 billion megawatthours – 2.2 percent higher than the output for 1984. The point-to-point compound average annual increase between 1981 and 1985 for energy requirements was 2.0 percent.

The 1985 annual load factor for the sum of the nine regions was 62.0 percent.

Table 1/SUMMER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (Megawatts)

Regions		1981	1982	1983	1984	1985	85/84 % Inc	Growth Rate 1981-1985*
NPCC	Installed Capability	50,504	50,563	50,508	51,312	51,319	0.0%	0.4%
	Peak Load	35,640	36,427	37,627	38,144	40,010	4.9%	2.9%
	Installed Margin	14,864	14,136	12,881	13,168	11,309		
	% Capacity Margin	29.4%	28.0%	25.5%	25.7%	22.0%		
MAAC	Installed Capability	45,109	46,461	46,734	46,183	47,157	2.1%	1.1%
	Peak Load	33,633	33,846	34,783	35,442	37,053	4.5%	2.5%
	Installed Margin	11,476	12,615	11,951	10,741	10,104		
	% Capacity Margin	25.4%	27.2%	25.6%	23.3%	21.4%		
ECAR	Installed Capability	89,495	89,919	90,914	90,115	92,960	3.2%	1.0%
	Peak Load	64,150	59,668	65,959	65,851	66,293	0.7%	0.8%
	Installed Margin	25,345	30,251	24,955	24,264	26,667		
	% Capacity Margin	28.3%	33.6%	27.4%	26.9%	28.7%		
SERC	Installed Capability	117,293	121,533	124,999	127,562	131,437	3.0%	2.9%
	Peak Load	90,513	86,229	97,235	93,400	98,572	5.5%	2.2%
	Installed Margin	26,780	35,304	27,764	34,162	32,865		
	% Capacity Margin	22.8%	29.0%	22.2%	26.8%	25.0%		
MAIN	Installed Capability	40,795	40,578	40,797	41,608	44,568	7.1%	2.2%
	Peak Load	32,561	31,394	34,704	35,186	32,432	−7.8%	−0.1%
	Installed Margin	8,234	9,184	6,093	6,422	12,136		
	% Capacity Margin	20.2%	22.6%	14.9%	15.4%	27.2%		
SPP	Installed Capability	54,215	58,236	59,294	60,389	62,225	3.0%	3.5%
	Peak Load	44,623	43,064	45,881	45,562	45,026	−1.2%	0.2%
	Installed Margin	9,592	15,172	13,413	14,827	17,199		
	% Capacity Margin	17.7%	26.1%	22.6%	24.6%	27.6%		
ERCOT	Installed Capability	43,045	43,452	43,800	44,056	43,829	−0.5%	0.5%
	Peak Load	32,535	33,231	34,972	36,851	38,062	3.3%	4.0%
	Installed Margin	10,510	10,221	8,828	7,205	5,767		
	% Capacity Margin	24.4%	23.5%	20.2%	16.4%	13.2%		
MAPP	Installed Capability	27,371	27,331	27,952	28,161	28,685	1.9%	1.2%
	Peak Load	18,985	19,470	20,785	20,666	19,936	−3.5%	1.2%
	Installed Margin	8,386	7,861	7,167	7,495	8,749		
	% Capacity Margin	30.6%	28.8%	25.6%	26.6%	30.5%		
WSCC	Installed Capability	104,392	108,069	111,451	114,854	119,417	4.0%	3.4%
	Peak Load	76,709	72,289	75,580	80,048	83,119	3.8%	2.0%
	Installed Margin	27,683	35,780	35,871	34,806	36,298		
	% Capacity Margin	26.5%	33.1%	32.2%	30.3%	30.4%		
TOTAL UNITED STATES**	Installed Capability	572,219	586,142	596,449	604,240	621,597	2.9%	2.1%
	Peak Load	429,349	415,618	447,526	451,150	460,503	2.1%	1.8%
	Installed Margin	142,870	170,524	148,923	153,090	161,094		
	% Capacity Margin	25.0%	29.1%	25.0%	25.3%	25.9%		

*Compound annual growth rate from 1981 to 1985

**U.S. totals are meaningless and should not be used for policy purposes

NOTE: For definitions of terms see page 5

Table 2/WINTER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (Megawatts)

Regions		1981/82	1982/83	1983/84	1984/85	1985/86	85/84 % Inc	Growth Rate 1981-1985*
NPCC	Installed Capability	53,060	52,289	52,018	53,076	52,984	−0.2%	0.0%
	Peak Load	35,199	34,755	35,836	37,321	38,233	2.4%	2.1%
	Installed Margin	17,861	17,534	16,182	15,755	14,751		
	% Capacity Margin	33.7%	33.5%	31.1%	29.7%	27.8%		
MAAC	Installed Capability	46,567	48,330	49,283	49,646	49,715	0.1%	1.6%
	Peak Load	30,726	28,197	30,150	33,384	31,652	−5.2%	0.7%
	Installed Margin	15,841	20,133	19,133	16,262	18,063		
	% Capacity Margin	34.0%	41.7%	38.8%	32.8%	36.3%		
ECAR	Installed Capability	91,731	91,045	91,642	94,304	95,750	1.5%	1.1%
	Peak Load	63,188	56,559	63,820	67,349	65,667	−2.5%	1.0%
	Installed Margin	28,543	34,486	27,822	26,955	30,083		
	% Capacity Margin	31.1%	37.9%	30.4%	28.6%	31.4%		
SERC	Installed Capability	122,379	125,575	129,941	129,105	134,754	4.4%	2.4%
	Peak Load	93,348	85,664	91,459	106,837	97,854	−8.4%	1.2%
	Installed Margin	29,031	39,911	38,482	22,268	36,900		
	% Capacity Margin	23.7%	31.8%	29.6%	17.2%	27.4%		
MAIN	Installed Capability	41,596	42,082	44,132	44,589	46,319	3.9%	2.7%
	Peak Load	26,965	24,303	28,159	27,805	29,060	4.5%	1.9%
	Installed Margin	14,631	17,779	15,973	16,784	17,259		
	% Capacity Margin	35.2%	42.2%	36.2%	37.6%	37.3		
SPP	Installed Capability	54,004	56,960	59,571	60,971	63,956	4.9%	4.3%
	Peak Load	32,087	32,743	35,799	35,112	34,618	−1.4%	1.9%
	Installed Margin	21,917	24,217	23,772	25,859	29,338		
	% Capacity Margin	40.6%	42.5%	39.9%	42.4%	45.9%		
ERCOT	Installed Capability	40,627	43,451	43,943	44,163	44,036	−0.3%	2.0%
	Peak Load	25,393	25,347	29,684	31,937	29,776	−6.8%	4.1%
	Installed Margin	15,234	18,104	14,259	12,226	14,260		
	% Capacity Margin	37.5%	41.7%	32.4%	27.7%	32.4%		
MAPP	Installed Capability	28,651	28,652	29,088	28,927	29,434	1.8%	0.7%
	Peak Load	17,508	17,816	18,807	18,989	18,803	−1.0%	1.8%
	Installed Margin	11,143	10,836	10,281	9,938	10,631		
	% Capacity Margin	38.9%	37.8%	35.3%	34.4%	36.1%		
WSCC	Installed Capability	107,954	109,682	112,835	117,344	119,527	1.9%	2.6%
	Peak Load	73,386	68,601	77,065	77,640	77,997	0.5%	1.5%
	Installed Margin	34,568	41,081	35,770	39,704	41,530		
	% Capacity Margin	32.0%	37.5%	31.7%	33.8%	34.7%		
TOTAL UNITED STATES**	Installed Capability	586,569	598,066	612,453	622,125	636,475	2.3%	2.1%
	Peak Load	397,800	373,985	410,779	436,374	423,660	−2.9%	1.6%
	Installed Margin	188,769	224,081	201,674	185,751	212,815		
	% Capacity Margin	32.2%	37.5%	32.9%	29.9%	33.4%		

*Compound annual growth rate from 1981/82 to 1985/86

**U.S. totals are meaningless and should not be used for policy purposes

NOTE: For definitions of terms see page 5

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS/1974-1985

The relationship between the summer and winter peak loads in the different regions of the country, and also for the contiguous United States, are shown in the accompanying table, where the summer peak load in each case is expressed as a percentage of the winter peak load for the following season.

In those regions where the summer peak load has been characteristically higher than the peak during the following winter, the percentage figure has, expectedly, been above 100 percent. This had been true particularly in SPP and ERCOT, where, due to climatic conditions, heavy air conditioning loads during the summer months have caused peaks that far exceed those during the following winter.

Since the mid-1960s, summer peaks for the country as a whole have generally exceeded the peaks for the following winter by increasing amounts. In 1970, and again in 1971, apparently normal summer peaks were followed by winter peaks depressed both by mild weather and reduced industrial loads. This combination produced summer to winter peak relationships of 111 percent and 112 percent respectively in 1970 and 1971.

After falling back to 110 percent in 1972, the summer/winter ratio jumped to an all-time high of 117 percent in 1973 because of the unprecedented drop in the winter peak load from the year previous. The ratio lowered only one point in 1974 since both the summer and winter peak loads were little changed from those experienced in 1973. Through the rest of the 1970s the ratio fluctuated in the more normal range of between 106 and 108 percent. The hot summer of 1980 and the economic downturn of 1981 helped to produce values of 111 and 108 percent respectively. In 1982 the summer peak dropped 3.2 percent and winter peak dropped 6.0 percent. The greater relative decline in the winter peak caused the summer/winter ratio to increase to 111 in 1982. The national ratio dropped to 109 percent in 1983. Then, due to a rebound in the 1984/85 winter peak load, the ratio fell to 103 percent in 1984, the lowest value registered since 1965. In 1985, more normal ratios occurred in the nine regions and the contiguous U.S. registered a value of 109 percent.

Table 3/SUMMER PEAK LOADS EXPRESSED AS PERCENTAGE OF PEAK LOAD FOR THE FOLLOWING WINTER

Regions	74/75	75/76	76/77	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86
NPCC	104	102	96	105	102	100	104	101	105	105	102	105
MAAC	123	114	108	115	111	114	116	109	120	115	106	117
ECAR	105	102	97	101	99	104	101	102	105	103	98	101
SERC	109	100	93	99	99	101	99	97	101	106	87	101
MAIN	125	119	122	122	118	123	127	121	129	123	127	112
SPP	156	124	144	144	138	133	147	139	132	128	130	130
ERCOT	157	141	142	142	134	130	132	128	131	118	115	128
MAPP	119	106	103	103	111	105	111	108	109	111	109	106
WSCC	107	104	107	107	98	100	107	105r	105	98	103	107
U.S. TOTAL	116	108	106	106	107	108	111	108r	111	109	103	109

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ANNUAL ENERGY REQUIREMENTS AND ANNUAL LOAD FACTORS/1981-1985

The 1985 energy requirements and annual load factors by reliability council are given in Tables 4 and 5, together with corresponding information for the previous four years.

Table 4 shows that during 1985 electric energy requirements for the contiguous United States amounted to 2.5 billion megawatthours – 2.2 percent higher than the output for 1984. The point-to-point compound average annual increase between 1981 and 1985 for energy requirements was 2.0 percent.

As can be seen from Table 5, the 1985 annual load factor for the sum of the nine regions was 62.0 percent. This was a rebound back to a more usual value in the low 60 percent range after the lower than normal national load factors experienced in 1983 and 1984.

Table 4/ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands)

Regions	1981	1982	1983	1984	1985	85/84 % Inc	Growth Rate 1981-1985*
NPCC	202,620	201,377	210,815	217,455	220,782	1.5%	2.2%
MAAC	174,688	171,662	179,990	186,034	189,671	2.0%	2.1%
ECAR	366,376	347,091	364,501	383,029	387,514	1.2%	1.4%
SERC	483,595	466,832	490,899	502,915	522,648	3.9%	2.0%
MAIN	162,899	158,116	165,974	170,930	173,589	1.6%	1.6%
SPP	211,833	211,595	217,688	225,642	229,677	1.8%	2.0%
ERCOT	164,920	169,769	173,372	185,283	190,758	3.0%	3.7%
MAPP	96,307	96,992	102,526	105,378	105,797	0.4%	2.4%
WSCC	447,788	435,310	435,868	468,937	478,790	2.1%	1.7%
TOTAL U.S.	2,311,026	2,258,744	2,341,633	2,445,603	2,499,226	2.2%	2.0%

*Compound annual growth rate from 1981 to 1985

Table 5/ANNUAL LOAD FACTOR, %

Regions	1981	1982	1983	1984	1985
NPCC	64.9	63.1	64.0	64.9	63.0
MAAC	59.3	57.9	59.1	59.8	58.4
ECAR	65.2	66.4	63.1	64.7	66.7
SERC	59.1	61.8	57.6	53.6	60.5
MAIN	57.1	57.5	54.6	55.3	61.1
SPP	54.2	56.1	54.2	56.4	58.2
ERCOT	57.9	58.3	56.6	57.2	57.2
MAPP	57.9	56.9	56.3	58.0	60.6
WSCC	66.6r	68.7r	64.6	66.7	65.8
TOTAL U.S.	61.0r	62.0r	59.5	59.7	62.0

Table 6A/CHANGES IN SCHEDULED OPERATION DATE OF NUCLEAR AND FOSSIL-FIRED STEAM TURBINE-GENERATORS, 300MW OR LARGER, REMOVED FROM SCHEDULE BETWEEN JANUARY 1, 1985 AND JANUARY 1, 1986

Owner	Unit Name & Number	Net Expected Capability MW	Scheduled Operation Date as of Jan. 1, 1985	Scheduled Operation Date as of Jan. 1, 1986
Nuclear Removals:		none		
Fossil Removals:				
Delmarva Power & Light Company	Vienna No. 9	375	5-95	Removed
General Public Utilities	Coal No. 2	625	5-97	Removed
Iowa Electric Light & Power Company	Guthrie County No. 1	650	12-95	Removed
Louisiana Power & Light Company	Wilton No. 1	800	1-93	Removed
Louisiana Power & Light Company	Wilton No. 2	800	1-97	Removed
Southwestern Public Service Company	South Plains Station No. 1	525	6-90	Removed
Southwestern Public Service Company	South Plains Station No. 2	525	6-93	Removed
Utah Power & Light Company	Blundell No. 2	10	6-87	Removed
Total Fossil Units Removed from Schedule		9 4,310		

Table 6B/CHANGES IN SCHEDULED OPERATION DATE OF NUCLEAR AND FOSSIL-FIRED STEAM TURBINE-GENERATORS, 300 MW OR LARGER, DELAYED A YEAR OR MORE BETWEEN JANUARY 1, 1985 AND JANUARY 1, 1986

Owner	Unit Name & Number		Net Expected Capability MW	Scheduled Operation Date as of Jan. 1, 1985	Scheduled Operation Date as of Jan. 1, 1986
Nuclear Delays					
Long Island Lighting Company	Shoreham No. 1		809	7-85	5-87
Mississippi Power & Light Company	Grand Gulf No. 2		1,250	4-91	99
Tennessee Valley Authority	Bellefonte No. 1		1,213	6-89	1-94
Tennessee Valley Authority	Bellefonte No. 2		1,213	6-91	1-96
Texas Utilities Company System	Comanche Peak No. 1		1,150	1-86	7-87
Washington Public Power Supply System	WNP No. 3		1,240	3-92	99
Washington Public Power Supply System	WNP No. 1		1,250	9-93	99
Total Nuclear Units Delayed One Year or More		7	8,125		
Fossil Delays					
Brazos Electric Power Coop	San Miguel No. 2		400	7-92	1-94
Central Power & Light Company	Coleto Creek No. 2		600	12-93	12-94
General Public Utilities	Coal No. 1		300	5-93	5-95
Lower Colorado River Authority	Fayette No. 4		400	6-91	7-92
Public Service Company of Colorado	Pawnee No. 2		485	4-91	4-94
Public Service Company of New Mexico	New Mexico Station No. 1		500	5-95	99
Public Service Company of New Mexico	New Mexico Station No. 2		500	5-96	99
Public Service Company of New Mexico	New Mexico Station No. 3		500	5-97	99
Public Service Company of New Mexico	New Mexico Station No. 4		500	5-98	99
Tucson Electric Power Company	Springerville No. 2		360	6-89	6-90
Total Fossil Units Delayed One Year or More		10	4,545		

The 1985 additions to electric generating capability in the contiguous United States are shown in the top part of Table VII according to the type of generating units. The second portion of the table presents the same information arranged according to the reliability councils in which the new capability was installed. The third portion of the table reports the same information classified according to ownership of the new units.

Table 7/1985 ADDITIONS TO ELECTRIC GENERATING CAPABILITY (In Terms of Net Expected Capabilities of the Units)

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped-Storage		Total	
	Nuclear		Conventional											
	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW
1985 ADDITIONS	7	7,892	15	5,505	1	50	3	18	20	1,076	6	2,100	52	16,641
ADDITIONS BY REGION														
NPCC	–	–	–	–	–	–	–	–	1	8	–	–	1	8
MAAC	1	1,050	–	–	–	–	–	–	3	114	–	–	4	1,164
ECAR	–	–	1	655	–	–	–	–	–	–	–	–	1	655
SERC	1	1,145	2	1,085	–	–	–	–	8	588	6	2,100	17	4,918
MAIN	1	1,120	2	960	–	–	2	11	–	–	–	–	5	2,091
SPP	3	3,504	2	1,148	–	–	1	7	–	–	–	–	6	4,659
ERCOT	–	–	1	728	–	–	–	–	–	–	–	–	1	728
MAPP	–	–	1	19	–	–	–	–	1	38	–	–	2	57
WSCC	1	1,073	6	910	1	50	–	–	7	328	–	–	15	2,361
ADDITIONS BY OWNERSHIP														
Investor-Owned	7	7,892	12	5,376	–	–	–	–	8	440	6	2,100	33	15,808
Federal	–	–	–	–	–	–	–	–	4	300	–	–	4	300
Municipal	–	–	1	19	1	50	3	18	5	302	–	–	10	389
Cooperative	–	–	–	–	–	–	–	–	–	–	–	–	–	–
State and Local	–	–	2	110	–	–	–	–	3	64	–	–	5	174

Table 8/1985 ADDITIONS TO ELECTRIC GENERATING CAPABILITY
U.S. Electric Power Systems
Units 4,000 Kw and Larger

SYMBOLS:

Investor-Owned	I
Federal	F
Municipal	M
Cooperative	C
State & Local	SL
Thermal	
Conventional steam turbine-generator	T
Nuclear steam turbine-generator	N
Combustion turbine-generator	G
Diesel engine-generator	D
Hydraulic	
Hydraulic turbine-generator	H
Pumped-Storage	
Pumped-storage turbine-generator	S
Reversible pumped-storage turbine-generator	R
Combined-Cycle	
Combustion turbine-generator for combined-cycle operation	GC
Conventional steam turbine-generator for combined-cycle operation	TC

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

NOTES: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the power systems; in other cases they represent the manufacturer's nameplate rating of the unit.

REGION	SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY
NPCC	CENTRAL MAINE POWER COMPANY	HIRAM	I	H		8
MAAC	+PENNSYLVANIA POWER & LIGHT COMPANY	SUSQUEHANNA NO 2	I	N		1,050
MAAC	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 8	I	H		38
MAAC	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 10	I	H		37
MAAC	SAFE HARBOR WATER POWER CORP	SAFE HARBOR NO 12	I	H		38
ECAR	DETROIT EDISON COMPANY	BELLE RIVER NO 2	I	T	Coal	655
SERC	ALABAMA POWER COMPANY	MILLER NO 2	I	T	Coal	666
SERC	ALABAMA POWER COMPANY	MITCHELL NO 5	I	H		64
SERC	ALABAMA POWER COMPANY	MITCHELL NO 6	I	H		64
SERC	ALABAMA POWER COMPANY	MITCHELL NO 7	I	H		64
SERC	DUKE POWER COMPANY	CATAWBA NO 1	I	N		1,145
SERC	GEORGIA POWER COMPANY	BARTLETTS FERRY 5 & 6	I	H		96
SERC	TAMPA ELECTRIC COMPANY	BIG BEND NO 4	I	T	Coal	419
SERC	U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 1	F	H		75
SERC	U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 2	F	H		75
SERC	U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 3	F	H		75
SERC	U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 4	F	H		75
SERC	+VIRGINIA ELECTRIC & POWER COMPANY	BATH COUNTY NO 1	I	R		350
SERC	+VIRGINIA ELECTRIC & POWER COMPANY	BATH COUNTY NO 2	I	R		350
SERC	+VIRGINIA ELECTRIC & POWER COMPANY	BATH COUNTY NO 3	I	R		350
SERC	+VIRGINIA ELECTRIC & POWER COMPANY	BATH COUNTY NO 4	I	R		350
SERC	+VIRGINIA ELECTRIC & POWER COMPANY	BATH COUNTY NO 5	I	R		350
SERC	+VIRGINIA ELECTRIC & POWER COMPANY	BATH COUNTY NO 6	I	R		350
MAIN	COMMONWEALTH EDISON COMPANY	BYRON NO 1	I	N		1,120
MAIN	MANITOWOC WISCONSIN	DIESEL NO 1	M	D		5
MAIN	MANITOWOC WISCONSIN	DIESEL NO 2	M	D		5
MAIN	WISCONSIN ELECTRIC POWER COMPANY	PLEASANT PRAIRIE NO 2	I	T	Coal	580
MAIN	+WISCONSIN POWER & LIGHT COMPANY	EDGEWATER NO 5	I	T	Coal	380

REGION	S Y S T E M	U N I T	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY
SPP	CHANUTE KANSAS	DIESEL A	M	D		7
SPP	+KANSAS GAS & ELECTRIC COMPANY	WOLF CREEK NO 1	I	N		1,150
SPP	LOUISIANA POWER & LIGHT COMPANY	WATERFORD NO 3	I	N		1,104
SPP	+MISSISSIPPI POWER & LIGHT COMPANY	GRAND GULF NO 1	I	N		1,250
SPP	+SOUTHWESTERN ELECTRIC POWER CO	PIRKEY NO 1	I	T	Coal	640
SPP	SOUTHWESTERN PUBLIC SERVICE CO	TOLK NO 2	I	T	Coal/Oil/Gas	508
ERCOT	HOUSTON LIGHTING & POWER COMPANY	LIMESTONE NO 1	I	T	Coal	728
MAPP	HIBBING MINNESOTA	MUNICIPAL	M	T	Sub-Bituminous	19
MAPP	NEBRASKA PUBLIC POWER DISTRICT	KINGSLEY NO 1	SL	H		38
WSCC	CALIFORNIA DEPT OF WATER RESOURCES	ALAMO NO 1	SL	H		17
WSCC	CALIFORNIA DEPT OF WATER RESOURCES	BOTTLE ROCK	SL	T	Geothermal	55
WSCC	GRANT COUNTY PUBLIC UTILITY DIST	QUINCY CHUTE	SL	H		10
WSCC	METROPOLITAN WATER DISTRICT	VALLEY VIEW NO 1	M	H		2
WSCC	NORTHERN CALIFORNIA POWER AGENCY	GEOTHERMAL NO 3	SL	T	Geothermal	55
WSCC	PACIFIC GAS & ELECTRIC COMPANY	DIABLO CANYON NO 1	I	N		1,073
WSCC	PACIFIC GAS & ELECTRIC COMPANY	GEYSERS NO 16	I	T	Geothermal	110
WSCC	PACIFIC GAS & ELECTRIC COMPANY	GEYSERS NO 20	I	T	Geothermal	110
WSCC	SACRAMENTO MUNICIPAL UTILITY DIST	JONES FORK	M	H		10
WSCC	SACRAMENTO MUNICIPAL UTILITY DIST	McLELLAN CT NO 1	M	G		50
WSCC	SEATTLE WASHINGTON	BOUNDARY NO 55	M	H		196
WSCC	+SIERRA PACIFIC POWER COMPANY	VALMY NO 2	I	T	Coal	250
WSCC	+TACOMA WASHINGTON	SUMMER FALLS NO 1	M	H		47
WSCC	+TACOMA WASHINGTON	SUMMER FALLS NO 2	M	H		47
WSCC	TUCSON GAS & ELECTRIC COMPANY	SPRINGERVILLE NO 1	I	T	Coal	330

52 GENERATING UNITS WERE ADDED WITH TOTAL NET EXPECTED CAPABILITY OF 16,641 MW

NUCLEAR ELECTRIC POWER GENERATING UNITS IN COMMERCIAL OPERATION

No steam turbine-generators for nuclear projects have been ordered since 1976, and no nuclear steam supply systems (reactors) since 1978.

As of January 1, 1986, nuclear capacity accounts for 55 percent of the aggregate of the industry's scheduled expansion program.

Table 9 shows subtotals of the amount of nuclear megawatts placed in service each year. As of January 1, 1986, there were 91 nuclear units in commercial operation with an aggregate winter rating of 74.9 thousand megawatts. There were seven additions to nuclear generating capacity during 1985.

NUCLEAR ELECTRIC POWER GENERATING UNITS IN COMMERCIAL OPERATION

Table 9/NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1986

SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMMERCIAL OPERATION	CAPABILITY SUMMER MW	CAPABILITY WINTER MW	YEARLY SUBTOTALS OF SUMMER MW RATINGS
1. Commonwealth Edison Company	Dresden No. 1	1960	197	207	197
2. Yankee Atomic Electric Co.	Yankee No. 1	1961	175	176	175
3. Consumers Power Company	Big Rock Point	1962	63	63	63
4. Washington Public Power Supply System	Hanford	1966	840	840	840
5. Connecticut Yankee Atomic Power Co.	Haddam No. 1	1968	555	580	
6. SoCal Edison & San Diego G&E	San Onofre No. 1	1968	436	436	991
7. GPU Nuclear Corporation	Oyster Creek No. 1	1969	620	650	
8. Niagara Mohawk Power Corp.	Nine Mile Point No. 1	1969	610	610	
9. Rochester Gas & Electric Corp.	Ginna No. 1	1969	470	470	1,700
10. Northeast Utilities	Millstone Point No. 1	1970	654	660	
11. Wisconsin Electric Power Co.	Point Beach No. 1	1970	495	495	1,149
12. Carolina Power & Light Co.	Robinson No. 2	1971	665	700	
13. Dairyland Power Cooperative	La Crosse	1971	46	46	
14. Northern States Power Company	Monticello No. 1	1971	536	557	
15. Commonwealth Edison Company	Dresden No. 2	1971	772	794	2,019
16. Boston Edison Company	Pilgrim No. 1	1972	670	670	
17. Commonwealth Edison Company	Quad Cities No. 1	1972	768	789	
18. Commonwealth Edison Company	Quad Cities No. 2	1972	769	789	
19. Florida Power & Light Company	Turkey Point No. 3	1972	666	696	
20. Maine Yankee Atomic Power Co.	Wiscasset	1972	814	830	
21. Vermont Yankee N. Power Corp.	Vernon	1972	496	528	
22. Virginia Electric & Power Co.	Surry No. 1	1972	775	775	4,958
23. Commonwealth Edison Company	Dresden No. 3	1973	773	794	
24. Consumers Power Company	Palisades No. 1	1973	635	740	
25. Duke Power Company	Oconee No. 1	1973	860	860	
26. Duke Power Company	Oconee No. 2	1973	860	860	
27. Florida Power & Light Company	Turkey Point No. 4	1973	666	696	
28. Northern States Power Company	Prairie Island No. 1	1973	503	523	
29. Omaha Public Power District	Fort Calhoun No. 1	1973	439	457	
30. Tennessee Valley Authority	Browns Ferry No. 1	1973	1,067	1,067	
31. Virginia Electric & Power Co.	Surry No. 2	1973	775	775	
32. Wisconsin Electric Power Co.	Point Beach No. 2	1973	495	495	7,073
33. Arkansas Power & Light Co.	Arkansas Nuclear No. 1	1974	836	836	
34. Commonwealth Edison Company	Zion No. 1	1974	1,040	1,040	
35. Commonwealth Edison Company	Zion No. 2	1974	1,040	1,040	
36. Consolidated Edison Co. of NY	Indian Point No. 2	1974	849	864	
37. Duke Power Company	Oconee No. 3	1974	860	860	
38. Iowa Electric Light & Power Co.	Arnold No. 1	1974	480	510	

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMMERCIAL OPERATION	CAPABILITY SUMMER MW	CAPABILITY WINTER MW	YEARLY SUBTOTALS OF SUMMER MW RATINGS
39	GPU Nuclear Corporation	Three Mile Island No. 1	1974	776	800	
40	Nebraska Public Power District	Cooper Nuclear No. 1	1974	778	778	
41	Northern States Power Company	Prairie Island No. 2	1974	500	520	
42	Philadelphia Electric Company	Peach Bottom No. 2	1974	1,051	1,055	
43	Philadelphia Electric Company	Peach Bottom No. 3	1974	1,035	1,035	
44	Wisconsin Public Service Corp.	Kewaunee No. 1	1974	525	517	9,770
45	Baltimore Gas & Electric Co.	Calvert Cliffs No. 1	1975	810	820	
46	Carolina Power & Light Company	Brunswick No. 2	1975	790	790	
47	Georgia Power Company	Hatch No. 1	1975	771	771	
48	Indiana & Michigan Electric Co.	Cook No. 1	1975	1,050	1,050	
49	New York Power Authority	Fitzpatrick No. 1	1975	821	821	
50	Sacramento Utility District	Rancho Seco No. 1	1975	875	903	
51	Tennessee Valley Authority	Browns Ferry No. 2	1975	1,067	1,067	6,184
52	Duquesne Light Company	Beaver Valley No. 1	1976	800	800	
53	Florida Power & Light Company	St. Lucie No. 1	1976	777	795	
54	Northeast Utilities	Millstone Point No. 2	1976	864	864	
55	Portland General Electric Co.	Trojan	1976	1,080	1,080	
56	New York Power Authority	Indian Point No. 3	1976	965	965	4,486
57	Alabama Power Company	Farley No. 1	1977	807	807	
58	Baltimore Gas & Electric Co.	Calvert Cliffs No. 2	1977	825	860	
59	Carolina Power & Light Company	Brunswick No. 1	1977	790	790	
60	Florida Power Corporation	Crystal River No. 3	1977	782	807	
61	Public Service Elec & Gas Co.	Salem Nuclear No. 1	1977	1,079	1,100	
62	Tennessee Valley Authority	Browns Ferry No. 3	1977	1,067	1,067	
63	Toledo Edison Company	Davis-Besse No. 1	1977	906	906	6,256
64	Indiana & Michigan Electric Co.	Cook No. 2	1978	1,100	1,100	
65	Virginia Electric & Power Co.	North Anna No. 1	1978	898	907	1,998
66	Georgia Power Company	Hatch No. 2	1979	771	771	
67	Public Service Co. of Colorado	Fort St. Vrain No. 1	1979	200	200	971
68	Arkansas Power & Light Co.	Arkansas Nuclear No. 2	1980	858	858	
69	Virginia Electric & Power Co.	North Anna No. 2	1980	870	870	1,728
70	Alabama Power Company	Farley No. 2	1981	812	812	
71	Duke Power Company	McGuire No. 1	1981	1,180	1,180	
72	Public Service Elec & Gas Co.	Salem Nuclear No. 2	1981	1,106	1,120	
73	Tennessee Valley Authority	Sequoyah No. 1	1981	1,128	1,128	4,226
74	Tennessee Valley Authority	Sequoyah No. 2	1982	1,148	1,148	1,148
75	Florida Power & Light Company	St. Lucie No. 2	1983	802	802	
76	Pennsylvania Power & Light Company	Susquehanna No. 1	1983	1,050	1,050	
77	SoCal Edison & San Diego G & E	San Onofre No. 2	1983	1,070	1,070	2,922
78	Commonwealth Edison Company	LaSalle County No. 1	1984	1,048	1,078	
79	Commonwealth Edison Company	LaSalle County No. 2	1984	1,048	1,078	
80	Duke Power Company	McGuire No. 2	1984	1,150	1,150	
81	South Carolina Electric & Gas Company	Summer No. 1	1984	885	885	
82	SoCal Edison & San Diego G & E Co.	San Onofre No. 3	1984	1,080	1,080	
83	Union Electric Company	Callaway No. 1	1984	1,109	1,123	
84	Washington Pub Power Supply System	WNP No. 2	1984	1,100	1,100	7,420
85	Commonwealth Edison Company	Byron No. 1	1985	1,120	1,120	
86	Duke Power Company	Catawba No. 1	1985	1,145	1,145	
87	Kansas Gas & Electric Company	Wolf Creek No. 1	1985	1,150	1,150	
88	Louisiana Power & Light Company	Waterford No. 3	1985	1,104	1,104	
89	Mississippi Power & Light Company	Grand Gulf No. 1	1985	1,250	1,250	
90	Pacific Gas & Electric Company	Diablo Canyon No. 1	1985	1,073	1,073	
91	Pennsylvania Power & Light Company	Susquehanna No. 2	1985	1,050	1,050	7,892
		91 Nuclear units totaling		74,166 SUMMER MW	74,948 WINTER MW	

SUMMER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

Summer peak capabilities, peak loads, and percent capacity margins as now forecast for the years 1986 through 1995 are shown in Table 1, page 21. Similar information for winter is shown in Table 2, page 23.

SUMMER CAPABILITIES

Except for WSCC, which shows higher expected summer capabilities throughout the 1986-94 period, the regional summer capability values shown in this report differ relatively slightly from the projections for the same years 12 months ago. For the nine regions taken together, changes range from increases of 0.3 percent in 1989 and 1990 to reductions of 1.5 percent in both 1993 and 1994.

The 1995 summer capability for the sum of the nine regions is projected at 714.6 thousand megawatts. This represents an average annual increase of 1.3 percent between the first and tenth forecast years.

SUMMER PEAK LOADS

Preliminary figures published in the 1985 Post-Summer Electric Power Survey indicated that the 1985 summer peak load was 1.4 percent above 1984. According to final data now available, the actual increase in the 1985 summer peak load was 2.1 percent.

Summer peak load forecasts have been reduced by five of the nine reliability councils, with the greatest percent reductions occurring in MAPP and SPP. NPCC increases averaged 3 percent from 1987 through 1994. MAAC, SERC, and WSCC increased their peak projections by lesser percentages. For the nine regions taken together, peak loads are only slightly changed, by no more than plus or minus 3 percent when compared with peak values shown for those years in the 1984 Electric Power Annual Report.

The summer peak load for the sum of the nine regions, which was 460.5 thousand megawatts in 1985, is projected to be 475.1 thousand megawatts in 1986, an increase of 3.2 percent. For the summer of 1995, the projection is 576.5 thousand megawatts. This represents an average annual increase of 2.2 percent between the first and tenth forecast years.

SUMMER PERCENT CAPACITY MARGINS

Of the 81 summer capacity margin percentages shown for the nine-year period 1986-1994 for the nine reliability councils, 53 of the values are lower than the equivalent respective values one year previous, 27 of the percent margins are higher, and one is unchanged.

NPCC, MAAC, and SERC show consistently lower percent margins from 1986 through 1994, and ECAR, ERCOT, and WSCC show more decreases than increases for the same period. MAIN, SPP, and MAPP show more increases than reductions in projected percent capacity margins.

Summer percent capacity margins for the country as a whole are higher from 1988 through 1990, and lower for 1986, 1987 and for 1991 through 1994. As now forecast, the summer capacity margins for the country range from 26.1 percent in 1987 to 19.3 percent in 1995, shown in these reports for the first time.

Table 10/SUMMER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS/1986-1995 PROJECTED
(Megawatts)

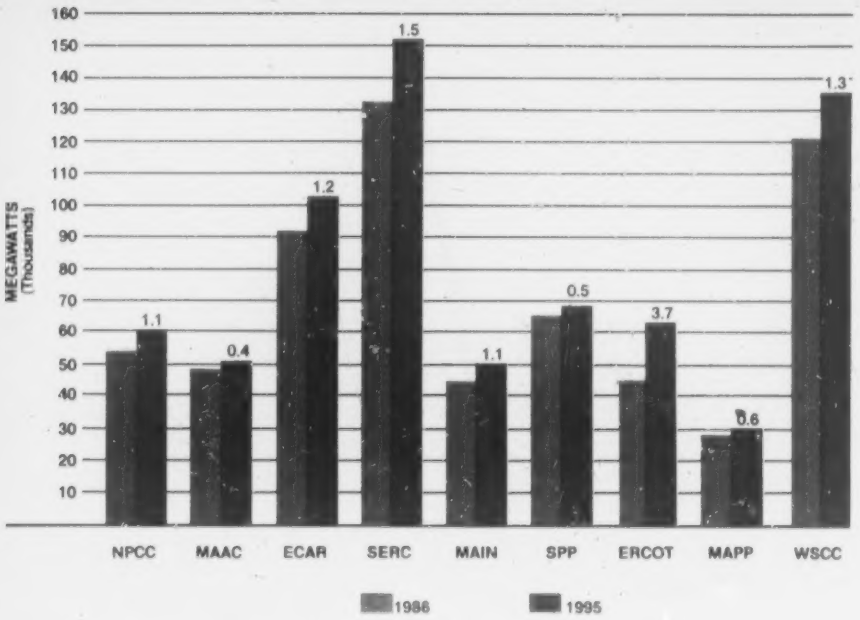
Regions		1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	Growth Rate 1986-1995*
NPCC	Capability	54,453	56,919	57,503	57,897	58,232	59,874	59,716	59,652	60,018	60,165	1.1%
	Peak Load	40,820	41,850	42,740	43,350	43,820	44,430	45,183	46,045	46,916	47,701	1.7%
	Installed Margin	13,633	15,069	14,763	14,547	14,412	15,444	14,533	13,607	13,102	12,464	
	% Capacity Margin	25.0%	26.5%	25.7%	25.1%	24.7%	25.8%	24.3%	22.8%	21.8%	20.7%	
MAAC	Capability	48,996	50,038	50,103	50,157	50,219	50,123	50,712	50,325	50,347	50,895	0.4%
	Peak Load	36,689	37,049	37,377	37,764	38,164	38,610	39,126	39,620	40,094	40,593	1.1%
	Installed Margin	12,307	12,989	12,726	12,393	12,055	11,513	11,586	10,705	10,253	10,302	
	% Capacity Margin	25.1%	26.0%	25.4%	24.7%	24.0%	23.0%	22.8%	21.3%	20.4%	20.2%	
ECAR	Capability	91,958	95,289	96,319	97,994	97,969	100,386	100,632	102,114	102,297	102,735	1.2%
	Peak Load	68,356	70,041	72,212	73,815	75,042	76,345	77,718	79,188	80,666	82,217	2.1%
	Installed Margin	23,602	25,248	24,107	24,179	21,927	24,041	22,914	21,926	21,631	20,518	
	% Capacity Margin	25.7%	26.5%	25.0%	24.7%	23.4%	23.9%	22.8%	22.5%	21.1%	20.0%	
SERC	Capability	132,845	138,649	140,557	144,111	144,512	146,501	147,887	148,093	149,506	151,603	1.5%
	Peak Load	100,818	103,571	106,023	109,122	111,675	114,645	117,165	119,642	122,134	124,619	2.4%
	Installed Margin	32,027	35,078	34,534	34,989	32,837	31,856	30,722	28,451	27,372	26,984	
	% Capacity Margin	24.1%	25.3%	24.6%	24.3%	22.7%	21.7%	20.8%	19.2%	18.3%	17.8%	
MAIN	Capability	45,536	48,389	48,076	49,319	49,239	49,432	49,563	50,277	50,389	50,424	1.1%
	Peak Load	35,752	36,211	36,658	37,246	37,779	38,400	39,024	39,649	40,287	40,940	1.5%
	Installed Margin	9,784	12,178	11,418	12,073	11,460	11,032	10,539	10,628	10,102	9,484	
	% Capacity Margin	21.5%	25.2%	23.7%	24.5%	23.3%	22.3%	21.3%	21.1%	20.0%	18.8%	
SPP	Capability	65,883	66,161	66,030	65,960	66,178	66,157	65,585	66,896	67,362	68,883	0.5%
	Peak Load	47,298	47,827	48,861	49,921	51,116	52,435	53,842	55,226	56,610	57,928	2.3%
	Installed Margin	18,585	18,334	17,169	16,039	15,062	13,722	11,743	11,670	10,752	10,955	
	% Capacity Margin	28.2%	27.7%	26.0%	24.3%	22.8%	20.7%	17.9%	17.4%	16.0%	15.9%	
ERCOT	Capability	45,806	48,610	51,629	52,939	53,736	54,713	56,838	58,758	60,945	63,360	3.7%
	Peak Load	38,957	40,239	41,247	42,784	44,394	46,082	47,613	49,436	51,200	53,052	3.5%
	Installed Margin	6,849	8,371	10,382	10,155	9,342	8,631	9,225	9,322	9,745	10,308	
	% Capacity Margin	15.0%	17.2%	20.1%	19.2%	17.4%	15.8%	16.2%	15.9%	16.0%	16.3%	
MAPP	Capability	28,998	29,221	29,754	29,782	30,111	30,305	30,305	30,202	30,271	30,715	0.6%
	Peak Load	21,541	22,126	22,478	22,901	23,334	23,651	24,059	24,520	24,956	25,386	1.8%
	Installed Margin	7,457	7,095	7,276	6,881	6,777	6,654	6,246	5,682	5,315	5,329	
	% Capacity Margin	25.7%	24.3%	24.5%	23.1%	22.5%	22.0%	20.6%	18.8%	17.6%	17.3%	
WSCC	Capability	121,418	124,994	127,985	128,861	130,621	131,096	131,943	132,872	134,835	135,853	1.3%
	Peak Load	84,862	87,292	89,615	91,773	93,380	95,448	97,468	99,988	102,050*	104,108	2.3%
	Installed Margin	36,556	37,702	38,370	37,088	37,241	35,648	34,475	32,884	32,785	31,745	
	% Capacity Margin	30.1%	30.2%	30.0%	28.8%	28.5%	27.2%	26.1%	24.7%	24.3%	23.4%	
TOTAL UNITED STATES**	Capability	635,893	658,270	667,956	677,020	680,817	688,587	693,181	699,189	705,970	714,633	1.3%
	Peak Load	475,093	486,206	497,211	508,676	518,704	530,046	541,198	553,314	564,913	576,544	2.2%
	Installed Margin	160,800	172,064	170,745	168,344	162,113	158,541	151,983	145,875	141,057	138,089	
	% Capacity Margin	25.3%	26.1%	25.6%	24.9%	23.8%	23.0%	21.9%	20.9%	20.0%	19.3%	

*Compound annual growth rate from 1986 to 1995

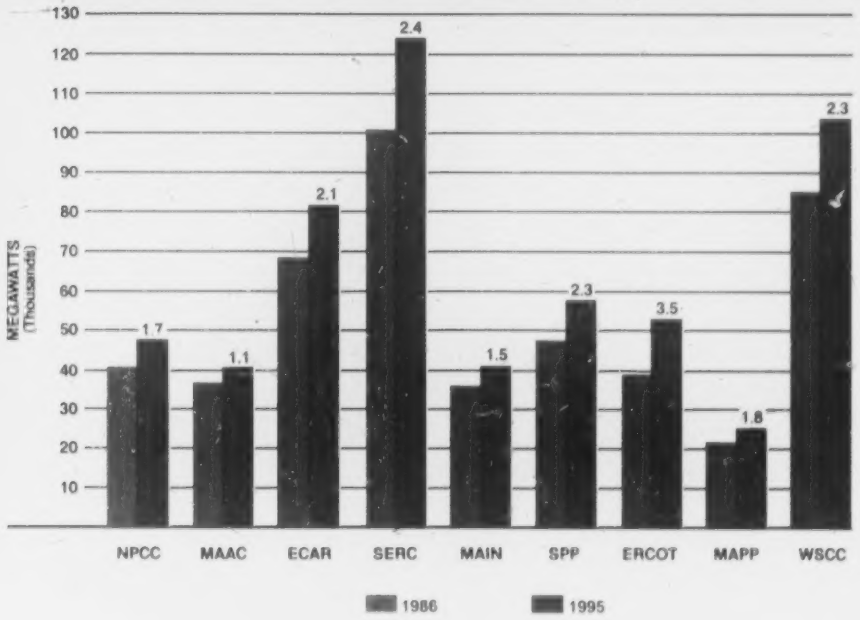
**U.S. totals are meaningless and should not be used for policy purposes

NOTE: For definitions of terms see page 5.
Capability equals NERC's "Planned Resources" series.

PROJECTED SUMMER CAPABILITIES
Average Annual Growth Rates



PROJECTED SUMMER PEAK LOADS
Average Annual Growth Rates



WINTER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

WINTER CAPABILITIES

Winter 1986/87 capability now projected for the entire electric utility industry is 654.5 thousand megawatts. The regional winter capability values shown in this report for 1986/87 through 1994/95 differ only slightly from the projections for the same years 12 months ago. For the nine regions taken together, changes range from increases of 0.1 percent in 1988 and 1989 to a reduction of 1.6 percent in 1993.

For winter 1995/96 the total capability of the industry is projected to reach 726.9 thousand megawatts. This value yields an average annual compound growth rate of 1.2 percent between the first and tenth forecast years.

The scheduled additions table on page 27 summarizes the number and aggregate ratings of new generating units that have so far been both ordered from the equipment manufacturers and been placed in the expansion program by having been assigned official scheduled dates of commercial operation. As of January 1, 1986, the furthest out year for which an ordered unit had been scheduled for operation was 2004.

WINTER PEAK LOADS

As now projected, the winter 1986/87 peak load for the contiguous U.S. is expected to be 434.8 thousand megawatts, an increase of 2.6 percent over the winter 1985/86 peak load. The new projections for 1986/87 through 1994/95 for the nine regions taken together generally show less than a one percent increase in each annual winter peak value for total U.S.

NPCC, MAAC, SERC, ERCOT and WSCC have raised their peak load projections for every year, with ERCOT showing the greatest relative increases. The other four councils have consistently lowered their projections throughout the period.

For winter 1995/96, the furthest out year projected in this report, the expected peak load is 533.4 thousand megawatts. This represents an average annual increase of 2.3 percent between the first and tenth forecast years.

WINTER PERCENT CAPACITY MARGINS

Compared with projected percent capacity margin values calculated on the same basis one year ago, NPCC, SERC, ERCOT, and WSCC show consistently reduced percent margins, SPP and MAPP show higher values throughout the period, and the other three councils show a mixture of increases and decreases. For the country as a whole, percent capacity margins are now projected to range from 34.6 percent for the winter of 1986/87 to 28.8 percent for 1994/95.

Table 11/WINTER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS/1986/87-1995/96 PROJECTED

Regions		1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	Growth Rate 1986-1995*
NPCC	Capability	55,485	57,962	58,517	58,773	60,693	60,427	60,510	60,526	60,836	60,615	1.0%
	Peak Load	39,003	39,940	40,660	41,220	41,740	42,370	43,026	43,879	44,679	45,419	1.7%
	Installed Margin	16,482	18,042	17,857	17,553	18,953	18,057	17,484	16,647	16,157	15,196	
	% Capacity Margin	29.7%	31.1%	30.5%	29.9%	31.2%	29.9%	28.9%	27.5%	26.6%	25.1%	
MAAC	Capability	51,370	52,437	52,502	52,514	51,816	52,169	52,880	52,743	52,756	53,304	0.4%
	Peak Load	32,742	33,323	33,944	34,638	35,338	36,038	36,696	37,337	37,968	38,590	1.8%
	Installed Margin	18,628	19,114	18,558	17,876	16,478	16,131	16,184	15,406	14,788	14,714	
	% Capacity Margin	36.3%	36.5%	35.3%	34.0%	31.8%	30.9%	30.6%	29.2%	28.0%	27.6%	
ECAR	Capability	96,799	97,373	99,468	99,486	99,881	101,844	102,590	103,601	103,883	104,545	0.9%
	Peak Load	67,355	69,380	71,077	72,375	73,694	75,079	76,496	78,077	79,609	81,079	2.1%
	Installed Margin	29,444	27,993	28,391	27,111	26,187	26,765	26,094	25,524	24,274	23,466	
	% Capacity Margin	30.4%	28.7%	28.5%	27.3%	26.2%	26.3%	25.4%	24.6%	23.4%	22.4%	
SERC	Capability	137,938	141,050	144,150	145,917	146,169	148,466	149,941	151,295	151,338	154,794	1.3%
	Peak Load	99,450	101,471	104,193	106,524	109,366	111,867	114,351	117,110	119,806	122,442	2.3%
	Installed Margin	38,488	39,579	39,957	39,393	36,803	36,599	35,590	34,185	31,532	32,352	
	% Capacity Margin	27.9%	28.1%	27.7%	27.0%	25.2%	24.7%	23.7%	22.6%	20.8%	20.9%	
MAIN	Capability	47,045	49,321	49,050	50,241	50,257	50,374	50,623	51,312	51,344	51,378	1.0%
	Peak Load	28,953	29,499	30,085	30,752	31,373	32,017	32,640	33,296	33,975	34,661	2.0%
	Installed Margin	18,092	19,822	18,965	19,489	18,884	18,357	17,983	18,016	17,369	16,717	
	% Capacity Margin	38.5%	40.2%	38.7%	38.8%	37.6%	36.4%	35.5%	35.1%	33.8%	32.5%	
SPP	Capability	66,224	66,451	66,399	66,277	66,325	66,203	66,042	67,256	68,598	69,889	0.6%
	Peak Load	34,829	35,816	36,453	37,426	38,487	39,537	40,625	41,717	42,822	43,863	2.6%
	Installed Margin	31,395	30,635	29,946	28,851	27,838	26,666	25,417	25,539	25,776	26,026	
	% Capacity Margin	47.4%	46.1%	45.1%	43.5%	42.0%	40.3%	38.5%	38.0%	37.6%	37.2%	
ERCOT	Capability	46,936	50,931	51,791	53,099	54,546	56,094	57,893	60,273	62,747	64,002	3.5%
	Peak Load	31,574	32,845	34,332	35,967	37,632	39,489	41,249	43,208	45,146	47,120	4.5%
	Installed Margin	15,362	18,086	17,459	17,132	16,914	16,605	16,644	17,065	17,601	16,882	
	% Capacity Margin	32.7%	35.5%	33.7%	32.3%	31.0%	29.6%	28.7%	28.3%	28.1%	26.4%	
MAPP	Capability	28,871	29,639	29,679	29,955	30,239	30,333	30,213	31,096	31,083	31,528	1.0%
	Peak Load	19,269	19,673	20,018	20,406	20,807	21,234	21,646	22,044	22,433	22,760	1.9%
	Installed Margin	9,602	9,966	9,661	9,549	9,432	9,099	8,567	9,052	8,650	8,768	
	% Capacity Margin	33.3%	33.6%	32.6%	31.9%	31.2%	30.0%	28.4%	29.1%	27.8%	27.8%	
WSCC	Capability	123,840	127,962	128,799	130,466	131,182	132,208	132,926	134,151	135,996	136,830	1.1%
	Peak Load	81,592	83,446	85,587	87,206	89,267	90,880	93,256	95,245	97,225	97,473	2.0%
	Installed Margin	42,248	45,516	43,212	43,260	41,915	41,328	39,670	38,906	38,771	39,357	
	% Capacity Margin	34.1%	34.8%	33.5%	33.2%	32.0%	31.3%	29.8%	29.0%	28.5%	28.8%	
TOTAL UNITED STATES**	Capability	654,508	673,146	680,355	686,728	691,108	698,118	703,618	712,253	718,581	726,885	1.2%
	Peak Load	434,767	445,393	456,349	466,514	477,704	488,511	499,985	511,913	523,663	533,407	2.3%
	Installed Margin	219,741	227,753	224,006	220,214	213,404	209,607	203,633	200,340	194,918	193,478	
	% Capacity Margin	33.6%	33.8%	32.9%	32.1%	30.9%	30.0%	28.9%	28.1%	27.1%	26.6%	

*Compound annual growth rate from 1986/87 to 1995/96

**U.S. totals are meaningless and should not be used for policy purposes

NOTE: For definitions of terms see page 5.
Capability equals NERC's "Planned Resources" series.

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS 1986-1995

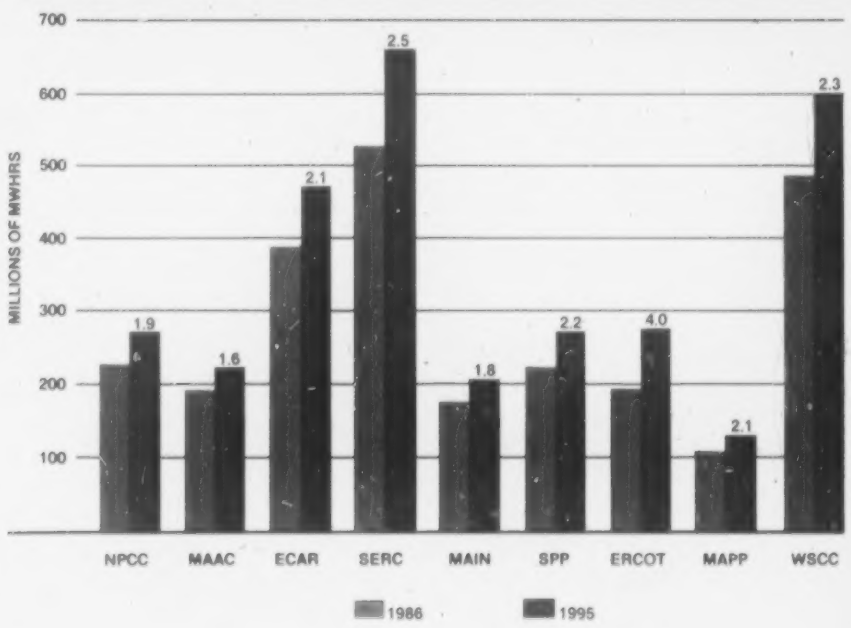
The relationship between the summer and winter peak loads in the different regions of the country, and also for the contiguous United States, are shown in the accompanying table, where the summer peak load in each case is expressed as a percentage of the winter peak load for the following season.

Though there are some changes from year to year in the regional ratios, the movements are generally offsetting to the extent that the summer/winter ratio for the sum of the nine regions calculates to either 109 percent or 108 percent throughout the ten-year period.

Table 12/SUMMER PEAK LOADS EXPRESSED AS PERCENTAGE OF PEAK LOADS FOR THE FOLLOWING WINTER/1986-1995

Regions	86/87	87/88	88/89	89/90	90/91	91/92	92/93	93/94	94/95	95/96
NPCC	105	105	105	105	105	105	105	105	105	105
MAAC	112	111	110	109	108	107	107	106	106	105
ECAR	101	101	102	102	102	102	102	101	101	101
SERC	101	102	102	102	102	102	102	102	102	102
MAIN	123	123	122	121	120	120	120	119	119	118
SPP	136	134	134	133	133	133	133	132	132	132
ERCOT	123	123	120	119	118	117	115	114	113	113
MAPP	112	112	112	112	112	111	111	111	111	112
WSCC	104	105	105	105	105	105	105	105	105	107
U.S.TOTAL	109	109	109	109	109	109	108	108	108	108

PROJECTED ANNUAL ENERGY Average Annual Growth Rates



ANNUAL ENERGY REQUIREMENTS AND ANNUAL LOAD FACTORS 1986-1995

Calendar-year energy requirements by region and for the total of the lower forty-eight states are shown in Table 13. The corresponding annual load factors are given in Table 14. The energy requirement represents utility generation plus megawatthours received from all outside sources, including net imports from other countries and energy from certain industrial installations which are interconnected and coordinated with the utility systems.

The present projections of energy requirements for the contiguous United States for the years 1986 through 1994 range between 1.0 and 1.3 percent below the values predicted in the 1984 Electric Power Annual Report. NPCC raised all its annual projected energy values, MAAC raised its projections very slightly only for 1986 through 1988, but all other regions show reduced values over the whole period. For 1995, the new furthest out year, the projected megawatthour requirement is 3.1 billion megawatthours. This represents an average annual increase of 2.3 percent between the first and tenth forecast years.

Table 13/ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands)/1986-1995

Regions	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	Annualized Growth Rate 1986-1995*
NPCC	226,628	232,399	237,903	241,708	245,065	248,972	253,487	258,365	263,335	268,044	1.9%
MAAC	191,748	194,009	196,952	200,168	203,569	207,168	210,691	214,190	217,718	221,084	1.6%
ECAR	389,000	399,400	414,800	424,000	430,900	437,900	445,700	453,300	461,300	469,400	2.1%
SERC	526,291	540,264	554,023	570,763	585,233	603,028	617,495	629,872	644,278	657,999	2.5%
MAIN	177,114	179,948	182,356	185,949	189,341	192,812	196,461	199,982	203,637	207,358	1.8%
SPP	223,357	224,517	229,434	233,950	239,590	245,599	252,642	259,087	265,426	271,718	2.2%
ERCOT	194,821	201,561	207,854	216,609	226,358	236,213	245,580	256,098	266,627	277,404	4.0%
MAPP	108,923	112,276	114,469	116,723	119,250	121,429	123,800	126,512	128,977	131,469	2.1%
WSCC	487,253	501,854	516,798	529,042	538,779	549,603	562,824	575,576	588,268	598,724	2.3%
TOTAL U.S.	2,525,135	2,586,228	2,654,589	2,718,912	2,778,085	2,842,724	2,908,680	2,972,982	3,039,566	3,103,200	2.3%

*Average annual growth rate from 1986 to 1995

Table 14/ANNUAL LOAD FACTOR, %/1986-1995

Regions	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
NPCC	63.4	63.4	63.4	63.6	63.8	64.0	63.9	64.1	64.1	64.1
MAAC	59.7	59.8	60.0	60.5	60.9	61.3	61.3	61.7	62.0	62.2
ECAR	65.0	65.1	65.4	65.6	65.5	65.5	65.3	65.3	65.3	65.2
SERC	59.6	59.5	59.5	59.7	59.8	60.0	60.0	60.1	60.2	60.3
MAIN	56.6	56.7	56.6	57.0	57.2	57.3	57.3	57.6	57.7	57.8
SPP	53.9	53.6	53.5	53.5	53.5	53.5	53.4	53.6	53.5	53.5
ERCOT	57.1	57.2	57.4	57.8	58.2	58.5	58.7	59.1	59.4	59.7
MAPP	57.7	57.9	58.0	58.2	58.3	58.6	58.6	58.9	59.0	59.1
WSCC	65.5	65.6	65.7	65.8	65.9	65.7	65.7	65.7	65.8	65.7
TOTAL U.S.	60.7	60.7	60.8	61.0	61.1	61.2	61.2	61.3	61.4	61.4

FUTURE EXPANSION PROGRAM

Table 16 shows that as of January 1, 1986, the electric power systems serving the contiguous United States had on order with both domestic and foreign manufacturers, and scheduled for commercial operation during 1986 and later years, a total of 69.4 thousand megawatts. This included 12 hydraulic units of both conventional and pumped-storage type, totaling 1.5 thousand megawatts. The thermal units include steam turbine-generators, of both conventional and nuclear types, a combustion turbine-generator, and three diesel engine-generators. Some of this capacity is on site and being installed; the remainder is under manufacture or in the form of firm orders.

During 1986, 14 nuclear power units are scheduled for commercial operation. These 14 units have an aggregate capability of 15.4 thousand megawatts. As of January 1, 1986, there are 20 additional nuclear units on order and scheduled for commercial operation in 1987 and later in the contiguous United States, having an aggregate capability of 22.9 thousand megawatts. These units are included in the regional listing designated Table 17.

An indeterminate number of units, amounting to several thousand megawatts, are also on order but are either awaiting their first assignment of a scheduled date of commercial operation by the utility systems, or were once scheduled and have since been removed from the expansion program. It is probable that the majority of the orders in the second category [being held open as options by the manufacturers] will not be reactivated.

Table 15 shows that of the total 67.6 thousand megawatts of steam turbine-generators on order as of January 1, 1986, and scheduled for service, nuclear and conventional units in sizes 700 megawatts and larger account for 73.9 percent of the total. Among the seven units in the less than 100 megawatt range, there are two coal-fired steam turbine-generators aggregating 94 megawatts, five geothermal units with a total capability of 261 megawatts.

Table 15/NUMBER AND AGGREGATE CAPABILITY OF STEAM TURBINE-GENERATORS IN THE EXPANSION PROGRAM GROUPED ACCORDING TO SIZE RANGE As of January 1, 1986

Size Range, MW	No Of Units	Aggregate Capability MW	Percent of Total
1,300 MW and Larger	2	2,600	3.8
1,200 to 1,299	11	13,681	20.2
1,100 to 1,199	13	14,864	22.0
1,000 to 1,099	5	5,350	7.9
900 to 999	3	2,790	4.1
800 to 899	5	4,058	6.0
700 to 799	9	6,662	9.9
600 to 699	10	6,327	9.4
500 to 599	9	4,605	6.8
400 to 499	9	3,935	5.8
300 to 399	5	1,664	2.5
200 to 299	1	250	0.4
100 to 199	4	491	0.7
Under 100	7	355	0.5
TOTAL STEAM UNITS	93	67,632	100.0

Table 16/SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY BASED ON SCHEDULED DATES OF COMMERCIAL OPERATION AS OF JANUARY 1, 1986
In Terms of Capability Ratings of the Units

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped-Storage		Total	
	Nuclear		Conventional											
	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW
TOTAL SCHEDULED	34	38,327	59	29,430	3	75	3	21	7	333	5	1,200	111	69,387
SCHEDULED ADDITIONS BY YEARS – as of January 1, 1986														
1986	14	15,412	13	6,020	3	75	3	21	5	297	–	–	38	21,826
1987	9	9,847	8	3,665	–	–	–	–	–	–	–	–	17	13,512
1988	4	4,597	8	3,011	–	–	–	–	2	36	1	200	15	7,844
1989	1	1,250	2	1,474	–	–	–	–	–	–	–	–	3	2,724
1990	–	–	2	424	–	–	–	–	–	–	–	–	2	424
1991	1	1,055	6	4,431	–	–	–	–	–	–	2	500	9	5,986
1992	–	–	4	2,390	–	–	–	–	–	–	2	500	6	2,890
1993	–	–	4	2,545	–	–	–	–	–	–	–	–	4	2,545
1994	1	1,213	4	2,235	–	–	–	–	–	–	–	–	5	3,448
1995	–	–	1	300	–	–	–	–	–	–	–	–	1	300
1996	1	1,213	1	540	–	–	–	–	–	–	–	–	2	1,753
1997	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1998	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1999	3	3,740	5	2,055	–	–	–	–	–	–	–	–	8	5,795
2004	–	–	1	340	–	–	–	–	–	–	–	–	1	340
SCHEDULED ADDITIONS BY REGION – as of January 1, 1986														
NPCC	4	4,189	–	–	–	–	–	–	–	–	–	–	4	4,189
MAAC	3	3,177	2	940	–	–	–	–	2	75	–	–	7	4,193
ECAR	3	3,131	9	5,484	–	–	1	7	–	–	–	–	13	8,622
SERC	8	9,125	11	5,852	–	–	–	–	–	–	4	1,000	23	15,977
MAIN	4	4,310	–	–	–	–	–	–	–	–	–	–	4	4,310
SPP	2	2,190	3	1,670	–	–	2	14	–	–	–	–	7	3,874
ERCOT	4	4,800	12	7,475	–	–	–	–	–	–	–	–	16	12,275
MAPP	–	–	3	1,387	–	–	–	–	2	36	–	–	5	1,423
WSCC	6	7,405	19	6,622	3	75	–	–	3	222	1	200	32	14,524
SCHEDULED ADDITIONS BY OWNERSHIP – as of January 1, 1986														
INVESTOR-OWNED	28	31,057	39	22,143	–	–	–	–	4	111	5	1,200	76	54,512
FEDERAL	4	4,780	–	–	–	–	–	–	–	–	–	–	4	4,780
MUNICIPAL	–	–	6	3,017	1	25	3	21	3	222	–	–	13	3,285
COOPERATIVE	–	–	5	1,914	–	–	–	–	–	–	–	–	5	1,914
STATE AND LOCAL	2	2,490	9	2,356	2	50	–	–	–	–	–	–	13	4,896

Table 17/SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY
Based on Scheduled Dates of Commercial Operation as of January 1, 1986

Includes all electric generating units 4,000 kW and larger on order and scheduled for service by the U.S. Electric Power Systems.

SYMBOLS:

Investor-Owned	I
Federal	F
Municipal	M
Cooperative	C
State & Local	SL
Thermal	
Conventional steam turbine-generator	T
Nuclear steam turbine-generator	N
Combustion turbine-generator	G
Diesel engine-generator	D
Hydraulic	
Hydraulic turbine-generator	H
Pumped-Storage	
Pumped-Storage turbine-generator	S
Reversible pumped-storage turbine-generator	R
Combined-Cycle	
Combustion turbine-generator for combined-cycle operation	GC
Conventional steam turbine-generator for combined-cycle operation	TC

° Denotes units added to the expansion program since July 1, 1985.

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

NOTES: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the power systems; in other cases they represent the manufacturer's nameplate rating of the unit.

REGION	S Y S T E M	U N I T	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
NPCC	LONG ISLAND LIGHTING CO	SHOREHAM NO 1	I	N		809	1987
NPCC	+NIAGARA MOHAWK POWER CORP	NINE MILE POINT NO 2	I	N		1,080	1986
NPCC	+NORTHEAST UTILITIES	MILLSTONE POINT NO 3	I	N		1,150	1986
NPCC	+PUBLIC SERVICE CO OF NEW HAMPSHIRE	SEABROOK NO 1	I	N		1,150	1986
4							

MAAC	BALTIMORE GAS & ELECTRIC CO	BRANDON SHORES NO 2	I	T	Oil/Coal	640	1992
MAAC	GENERAL PUBLIC UTILITIES	COAL NO 1	I	T	Coal	300	1995
MAAC	PHILADELPHIA ELECTRIC CO	LIMERICK NO 1	I	N		1,055	1986
MAAC	PHILADELPHIA ELECTRIC CO	LIMERICK NO 2	I	N		1,055	1991
MAAC	+PUBLIC SERVICE ELECTRIC & GAS CO	HOPE CREEK NO 1	I	N		1,067	1986
MAAC	SAFE HARBOR WATER CORPORATION	SAFE HARBOR NO 9	I	H		38	1986
MAAC	SAFE HARBOR WATER CORPORATION	SAFE HARBOR NO 11	I	H		38	1986
7							

ECAR	AMERICAN ELECTRIC POWER CO	ROCKPORT NO 2	I	T	Coal	1,300	1988
ECAR	BAY CITY MICHIGAN	MUNICIPAL	M	D		7	1986
ECAR	CINCINNATI GAS & ELECTRIC CO	ZIMMER	I	T	Coal	1,300	1991
ECAR	+CLEVELAND ELECTRIC ILLUMINATING CO	PERRY NO 1	I	N		1,205	1986
ECAR	+DETROIT EDISON COMPANY	FERMI NO 2	I	N		1,093	1986
ECAR	+DUQUESNE LIGHT COMPANY	BEAVER VALLEY NO 2	I	N		833	1987
ECAR	EAST KENTUCKY POWER COOP	SMITH NO 1	C	T	Unknown	600	1992
ECAR	INDIANAPOLIS POWER & LIGHT CO	PETERSBURG NO 4	I	T	Coal	515	1986
ECAR	KENTUCKY UTILITIES CO	HANCOCK NO 1	I	T	Coal	650	1993
ECAR	LOUISVILLE GAS & ELECTRIC CO	TRIMBLE COUNTY NO 1	I	T	Coal	495	1988
ECAR	NORTHERN INDIANA PUBLIC SERVICE CO	SCHAHFER NO 18	I	T	Coal	344	1986
ECAR	SOUTHERN INDIANA GAS & ELECTRIC CO	BROWN NO 2	I	T	Coal	250	1986
ECAR	WYANDOTTE MICHIGAN	WYANDOTTE NO 7	M	T	Coal	30	1986
13							

REGION	S Y S T E M	U N I T	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
SERC	ALABAMA POWER COMPANY	MILLER NO 3	I	T	Coal	666	1989
SERC	ALABAMA POWER COMPANY	MILLER NO 4	I	T	Coal	666	1991
SERC	CAROLINA POWER & LIGHT CO	HARRIS NO 1	I	N		900	1986
SERC	CAROLINA POWER & LIGHT CO	MAYO NO 2	I	T	Coal	720	1991
SERC	DUKE POWER COMPANY	BAD CREEK NO 1	I	R		250	1991
SERC	DUKE POWER COMPANY	BAD CREEK NO 2	I	R		250	1991
SERC	DUKE POWER COMPANY	BAD CREEK NO 3	I	R		250	1992
SERC	DUKE POWER COMPANY	BAD CREEK NO 4	I	R		250	1992
SERC	DUKE POWER COMPANY	CATAWBA NO 2	I	N		1,145	1987
SERC	+GEORGIA POWER COMPANY	SCHERER NO 3	I	T	Coal	808	1987
SERC	+GEORGIA POWER COMPANY	SCHERER NO 4	I	T	Coal	808	1989
SERC	+GEORGIA POWER COMPANY	VOGTLE NO 1	I	N		1,150	1987
SERC	+GEORGIA POWER COMPANY	VOGTLE NO 2	I	N		1,150	1988
SERC	+JACKSONVILLE FLORIDA	ST JOHNS RIVER PARK 1	M	T	Coal	525	1987
SERC	+JACKSONVILLE FLORIDA	ST JOHNS RIVER PARK 2	M	T	Coal	525	1988
SERC	+ORLANDO FLORIDA	STANTON NO 1	M	T	Coal	415	1987
SERC	SOUTH CAROLINA PUBLIC SERVICE AUTHY	CROSS NO 1	SL	T	Coal	500	1993
SERC	TENNESSEE VALLEY AUTHORITY	BELLEFONTE NO 1	F	N		1,213	1994
SERC	TENNESSEE VALLEY AUTHORITY	BELLEFONTE NO 2	F	N		1,213	1996
SERC	TENNESSEE VALLEY AUTHORITY	WATTS BAR NO 1	F	N		1,177	1986
SERC	TENNESSEE VALLEY AUTHORITY	WATTS BAR NO 2	F	N		1,177	1988
SERC	VIRGINIA ELECTRIC & POWER CO	PORTSMOUTH NO 1	I	T	Coal	107	1987
SERC	VIRGINIA ELECTRIC & POWER CO	PORTSMOUTH NO 2	I	T	Coal	112	1987
23							

MAIN	COMMONWEALTH EDISON CO	BRAIDWOOD NO 1	I	N		1,120	1987
MAIN	COMMONWEALTH EDISON CO	BRAIDWOOD NO 2	I	N		1,120	1988
MAIN	COMMONWEALTH EDISON CO	BYRON NO 2	I	N		1,120	1987
MAIN	+ILLINOIS POWER COMPANY	CLINTON NO 1	I	N		950	1986
4							

REGION	S Y S T E M	U N I T	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
SPP	CHANUTE KANSAS	DIESEL B	M	D		7	1986
SPP	CHANUTE KANSAS	DIESEL C	M	D		7	1986
SPP	GRAND RIVER DAM AUTHORITY	GRDA ONE UNIT 2	SL	T	Coal	490	1986
SPP	GULF STATES UTILITIES	NELSON NO 5	I	T	Coal	540	1996
SPP	+GULF STATES UTILITIES	RIVER BEND NO 1	I	N		940	1986
SPP	+MISSISSIPPI POWER & LIGHT CO	GRAND GULF NO 2	I	N		1,250	1999
SPP	+SOUTHWESTERN ELECTRIC POWER CO	DOLET HILLS NO 1	I	T	Coal	640	1986
7							
ERCOT	+BRAZOS ELECTRIC POWER COOP	SAN MIGUEL NO 2	C	T	Coal/Oil	400	1994
ERCOT	+CENTRAL POWER & LIGHT CO	COLETO CREEK NO 2	I	T	Coal	600	1994
ERCOT	HOUSTON LIGHTING & POWER CO	LIMESTONE NO 2	I	T	Coal	720	1986
ERCOT	HOUSTON LIGHTING & POWER CO	MALAKOFF NO 1	I	T	Coal	645	1991
ERCOT	HOUSTON LIGHTING & POWER CO	MALAKOFF NO 2	I	T	Coal	645	1993
ERCOT	+HOUSTON LIGHTING & POWER CO	SOUTH TEXAS NO 1	I	N		1,250	1987
ERCOT	+HOUSTON LIGHTING & POWER CO	SOUTH TEXAS NO 2	I	N		1,250	1989
ERCOT	+LOWER COLORADO RIVER AUTHORITY	FAYETTE NO 3	SL	T	Coal	400	1988
ERCOT	o+LOWER COLORADO RIVER AUTHORITY	FAYETTE NO 4	SL	T	Coal	400	1992
ERCOT	+TEXAS UTILITIES CO SYSTEM	COMANCHE PEAK NO 1	I	N		1,150	1987
ERCOT	+TEXAS UTILITIES CO SYSTEM	COMANCHE PEAK NO 2	I	N		1,150	1988
ERCOT	+TEXAS UTILITIES CO SYSTEM	FOREST GROVE NO 1	I	T	Coal	750	1993
ERCOT	+TEXAS UTILITIES CO SYSTEM	MARTIN LAKE NO 4	I	T	Coal	750	1994
ERCOT	+TEXAS UTILITIES CO SYSTEM	TWIN OAK NO 1	I	T	Coal	750	1991
ERCOT	+TEXAS UTILITIES CO SYSTEM	TWIN OAK NO 2	I	T	Coal	750	1992
ERCOT	+WEST TEXAS UTILITIES	OKLAUNION NO1	I	T	Coal	665	1986
16							
MAPP	+BASIN ELECTRIC POWER COOP	ANTELOPE VALLEY NO 2	C	T	Coal	450	1986
MAPP	NORTHERN STATES POWER CO	JIM FALLS NO 1	I	H		18	1988
MAPP	NORTHERN STATES POWER CO	JIM FALLS NO 2	I	H		18	1988
MAPP	oNORTHERN STATES POWER CO	RIVERSIDE 6&7 CAP R	I	T	Coal	137	1987
MAPP	+NORTHERN STATES POWER CO	SHERBURNE COUNTY NO 3	I	T	Coal	800	1987
5							

REGION	S Y S T E M	U N I T	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
WSCC	ARIZONA PUBLIC SERVICE CO	CHOLLA NO 5	I	T	Coal	340	2004
WSCC	+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 1	I	N		1,270	1986
WSCC	+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 2	I	N		1,270	1986
WSCC	+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 3	I	N		1,270	1987
WSCC	CALIFORNIA DEPT OF WATER RESOURCES	SOUTH GEYSERS	SL	T	Geothermal	55	1999
WSCC	CENTRAL CALIFORNIA POWER AGENCY	GEYSERS NO 1A	SL	T	Geothermal	53	1988
WSCC	CENTRAL CALIFORNIA POWER AGENCY	GEYSERS NO 1B	SL	T	Geothermal	53	1988
WSCC	COLORADO-UTE ELECTRIC ASSOCIATION	NUCLA NO 4	C	T	Coal	64	1990
WSCC	DESERET G & T COOP	BONANZA NO 1	C	T	Coal	400	1986
WSCC	+LOS ANGELES CALIFORNIA	INTERMOUNTAIN NO 1	M	T	Coal	761	1986
WSCC	+LOS ANGELES CALIFORNIA	INTERMOUNTAIN NO 2	M	T	Coal	761	1987
WSCC	METROPOLITAN WATER DISTRICT	RED MOUNTAIN NO 1	M	H		4	1986
WSCC	+MONTANA POWER COMPANY	COLSTRIP NO 4	I	T	Coal	700	1986
WSCC	NORTHERN CALIFORNIA POWER AGENCY	GEOTHERMAL NO 4	SL	T	Geothermal	55	1986
WSCC	PACIFIC GAS & ELECTRIC CO	DIABLO CANYON NO 2	I	N		1,105	1986
WSCC	oPACIFIC GAS & ELECTRIC CO	GEYSERS NO 21	I	T	Geothermal	140	1988
WSCC	PUBLIC SERVICE CO OF COLORADO	PAWNEE NO 2	I	T	Coal	485	1994
WSCC	+PUBLIC SERVICE CO OF NEW MEXICO	NEW MEX STATION NO 1	I	T	Coal	500	1999
WSCC	PUBLIC SERVICE CO OF NEW MEXICO	NEW MEX STATION NO 2	I	T	Coal	500	1999
WSCC	PUBLIC SERVICE CO OF NEW MEXICO	NEW MEX STATION NO 3	I	T	Coal	500	1999
WSCC	PUBLIC SERVICE CO OF NEW MEXICO	NEW MEX STATION NO 4	I	T	Coal	500	1999
WSCC	SALT RIVER POWER DISTRICT	CORONADO NO 3	SL	T	Coal	350	1991
WSCC	SAN DIEGO GAS & ELECTRIC CO	HEBER NO 2	I	T	Geothermal	45	1988
WSCC	oSANTA CLARA CALIFORNIA	COMBUSTION TURBINE	M	G		25	1986
WSCC	SEATTLE WASHINGTON	BOUNDARY NO 56	M	H		196	1986
WSCC	SOUTHERN CALIFORNIA EDISON CO	BALSAM MEADOW NO 1	I	R		200	1988
WSCC	TACOMA WASHINGTON	MAIN CANAL HEADWORKS	M	H		22	1986
WSCC	TUCSON ELECTRIC POWER CO	SPRINGERVILLE NO 2	I	T	Coal	360	1990
WSCC	TURLOCK IRRIGATION DISTRICT	GT PROJECT NO 1	SL	G		25	1986
WSCC	TURLOCK IRRIGATION DISTRICT	GT PROJECT NO 2	SL	G		25	1986
WSCC	+WASHINGTON PUB PWR SPLY SYSTEM	WNP NO 1	SL	N		1,250	1999
WSCC	+WASHINGTON PUB PWR SPLY SYSTEM	WNP NO 3	SL	N		1,240	1999
32					111 units:	69,387 MW	

PART III—MANUFACTURE OF HEAVY ELECTRIC POWER EQUIPMENT

(HISTORICAL AND SCHEDULED)

Data in this section of the report relate to the manufacture in the United States of heavy electric power equipment for U.S. electric power systems. U.S. Industrials and for export to customers outside the United States. Information is also included on actual and scheduled imports of such equipment by U.S. electric power systems.

Orders placed with domestic and foreign manufacturers during 1985 for heavy electric power equipment by U.S. electric power systems are shown in the accompanying order synopsis table (Table 18), together with corresponding information for the previous four years.

Detailed data, as of January 1, 1986, concerning 1985 orders, shipments, scheduled shipments, and total production backlogs of domestic manufacturers for the three customer classes are shown in the series of tables that follow, along with analogous information on imports of certain types of equipment by U.S. electric power systems only.

During 1985, orders for new electric generating units, steam and hydraulic, placed with domestic manufacturers totaled 45 machines aggregating 5,220 megawatts. U.S. electric power systems accounted for 28.2 percent of this total capacity, U.S. industrials for 16.9 percent, and exports took 54.9 percent. The only orders placed in 1985 with foreign manufacturers by U.S electric power systems were for three water-wheel generators aggregating 69 megawatts, one hydraulic turbine for 235,000 Hp, and a single steam turbine-generator rated at 168 megawatts.

Production by domestic manufacturers during the year 1985 amounted to 7.3 thousand megawatts, of which 4.6 thousand megawatts were delivered to U.S. electric power systems. The total production scheduled as of January 1, 1986, for all classes of customers amounts to 128 units totaling 54.3 thousand megawatts. The manufacturing schedule for 1986 totals 3.0 thousand megawatts. The 1987 and later schedule, up to now, calls for the production of 96 units totaling 51.3 thousand megawatts.

Table 18/CAPACITIES OF VARIOUS TYPES OF EQUIPMENT ORDERED BY U.S. ELECTRIC POWER SYSTEMS FROM DOMESTIC AND FOREIGN MANUFACTURERS

		1981	1982	1983	1984	1985
Electric Generating Units (4,000 kW and Larger)						
Steam Turbine-Generators, kW						
Conventional		7,324,394 (a)	—	591,465	683,100	1,379,454
Nuclear		—	—	—	—	—
Geothermal, kW		380,100	93,500	110,000	139,240 (a)	168,000 (a)
Solar, kW		—	—	14,700	30,000	90,000
Combustion Turbine-Generators, kW		524,580	35,790	75,000 (a)	162,000	24,800
Generators for Hydraulic Turbines, kW		209,340 (a)	279,326 (a)	869,367 (a)	—	69,200
	TOTALS	8,438,414 (a)	408,616 (a)	1,660,532 (a)	1,014,340 (a)	1,731,454 (a)
Steam Generators, 1,000 Lb Steam Per Hour		51,880	1,000	4,700	3,900	—
Nuclear Power Reactors (50,000 kWe and Larger)		—	—	—	—	—
Hydraulic Turbines, Hp		40,000	—	—	—	235,000
Power Transformers, MVA (b)		91,093	78,003	69,495	65,688	65,037

(a) Includes equipment on order with foreign manufacturers.
(b) Includes U.S. Industrials.

Table 19/MANUFACTURE OF ELECTRIC GENERATING EQUIPMENT—STEAM AND HYDRAULIC UNITS* (4,000 kW and Larger)

Customer	Shipped	Scheduled as of January 1, 1986		Total Scheduled for Shipment as of 1-1-86	New Orders Booked
	1985	1986	1987 and Later		1985
U.S. Electric Power Systems					
Units	9	7	73	80	9
kW	4,627,167	945,240	45,042,348	45,987,588	1,469,454
U.S. Industrials					
Units	27	17	14	31	28
kW	689,650	431,200	509,975	941,175	884,450
Exports from U.S.					
Units	5	8	9	17	8
kW	1,938,496	1,612,496	5,794,000	7,406,496	2,866,000
Total					
Units	41	32	96	128	45
kW	7,255,313	2,988,936	51,346,323	54,335,259	5,219,904

*Does not include combustion turbine-generators, but does include steam turbine-generators for nuclear power plants.

Table 20/MANUFACTURE OF STEAM TURBINE-GENERATORS (4,000 kW and Larger)

Customer	Shipped	Scheduled as of January 1, 1986		Total Scheduled for Shipment as of 1-1-86	New Orders Booked
	1985	1986	1987 and Later		1985
U.S. Electric Power Systems					
Units	9	7	73	80	9
kW	4,627,167	945,240	45,042,348	45,987,588	1,469,454
U.S. Industrials					
Units	27	17	14	31	28
kW	689,650	431,200	509,975	941,175	884,450
Exports from U.S.					
Units	5	8	9	17	8
kW	1,938,496	1,612,496	5,794,000	7,406,496	2,866,000
Total					
Units	41	32	96	128	45
kW	7,255,313	2,988,396	51,346,323	54,335,259	5,219,904

Table 20-A/MANUFACTURE OF CONVENTIONAL STEAM TURBINE-GENERATORS (4,000 kW and Larger) (Included in Table 20)

Customer	Shipped 1985	Scheduled as of January 1, 1986: 1986	Scheduled as of January 1, 1986: 1987 and Later	Total Scheduled for Shipment as of 1-1-86	New Orders Booked 1985
U.S. Electric Power Systems					
Units	9	7	68	75	9
kW	4,627,167	945,240	39,778,370	40,723,610	1,469,454
U.S. Industrials					
Units	27	17	14	31	28
kW	689,650	431,200	509,975	941,175	884,450
Exports from U.S.					
Units	4	7	6	13	8
kW	1,232,000	906,000	3,694,000	4,600,000	2,866,000
Total					
Units	40	31	88	119	45
kW	6,548,817	2,282,440	43,982,345	46,264,785	5,219,904
U.S.E.P.S. Orders to Foreign Manufacturers (Imports)					
Units	5	5	4	9	1
kW	317,200	504,240	1,567,000	2,071,240	168,000

Table 20-B/MANUFACTURE OF NUCLEAR STEAM TURBINE-GENERATORS (50,000 kWe and Larger) (Included in Table 20)

Customer	Shipped 1985	Scheduled as of January 1, 1986: 1986	Scheduled as of January 1, 1986: 1987 and Later	Total Scheduled for Shipment as of 1-1-86	New Orders Booked 1985
U.S. Electric Power Systems					
Units			5	5	
kW			5,263,978	5,263,978	
U.S. Industrials					
Units					
kW					
Exports from U.S.					
Units	1	1	3	4	
kW	706,496	706,496	2,100,000	2,806,496	
Total					
Units	1	1	8	9	
kW	706,496	706,496	7,363,978	8,070,474	
U.S.E.P.S. Orders to Foreign Manufacturers (Imports)					
Units					
kW					

Table 21/MANUFACTURE OF GENERATORS FOR HYDRAULIC TURBINES* (4,000 kW and Larger)

Customer	Shipped 1985	Scheduled as of January 1, 1986: 1986	Scheduled as of January 1, 1986: 1987 and Later	Total Scheduled for Shipment as of 1-1-86	New Orders Booked 1985
U.S. Electric Power Systems					
Units	—	—	—	—	—
kW	—	—	—	—	—
U.S. Industrials					
Units	—	—	—	—	—
kW	—	—	—	—	—
Exports from U.S.					
Units	—	—	—	—	—
kW	—	—	—	—	—
Total					
Units	—	—	—	—	—
kW	—	—	—	—	—
U.S.E.P.S. Orders to Foreign Manufacturers (Imports)					
Units	3	2	12	14	3
kW	101,250	207,200	1,336,550	1,543,750	69,200

*Includes generators for pumped-storage plants

Table 22/MANUFACTURE OF CONVENTIONAL STEAM GENERATORS (450 Psi Pressure and Higher)

Customer	Shipped 1985	Scheduled as of January 1, 1986: 1986	Scheduled as of January 1, 1986: 1987 and Later	Total Scheduled for Shipment as of 1-1-86	New Orders Booked 1985
U.S. Electric Power Systems					
Units	6	3	16	19	—
M Lb/Hr	28,644	14,360	84,403	98,763	—
U.S. Industrials					
Units	8	7	—	7	11
M Lb/Hr	1,180	696	—	696	1,158
Exports from U.S.					
Units	3	1	—	1	—
M Lb/Hr	9,496	3,748	—	3,748	—
Total					
Units	17	11	16	27	11
M Lb/Hr	39,320	18,804	84,403	103,207	1,158

Table 23/MANUFACTURE OF HYDRAULIC TURBINES*
(5,000 Horsepower and Larger)

Customer	Shipped	Scheduled as of January 1, 1986		Total Scheduled for Shipment as of 1-1-86	New Orders Booked
	1985	1986	1987 and Later		1985
U.S. Electric Power Systems					
Units	6	–	4	4	–
Hp	770,000	–	1,380,000	1,380,000	
U.S. Industrials					
Units	–	3	–	3	3
Hp	–	70,480	–	70,480	70,480
Exports from U.S.					
Units	2	–	–	–	–
Hp	183,600	–	–	–	–
Total					
Units	8	3	4	7	3
Hp	953,600	70,480	1,380,000	1,450,480	70,480
U.S. E.P.S. Orders to Foreign Manufacturers (Imports)					
Units	–	2	–	2	1
Hp	–	257,600	–	257,600	235,000

* Includes hydraulic turbines for pumped-storage plants.

Table 24/MANUFACTURE OF COMBUSTION TURBINE-GENERATORS
(4,000 kW and Larger)

Customer	Shipped	Scheduled as of January 1, 1986		Total Scheduled for Shipment as of 1-1-86	New Orders Booked
	1985	1986	1987 and Later		1985
U.S. Electric Power Systems					
Units	4	–	–	–	1
kW	111,000	–	–	–	24,800
U.S. Industrials					
Units	10	2	6	8	13
kW	1,187,400	115,100	386,800	501,900	794,800
Exports from U.S.					
Units	5	11	2	13	14
kW	317,800	994,100	219,800	1,213,900	1,238,700
Total					
Units	28	13	8	21	28
kW	1,616,200	1,109,200	606,000	1,715,800	2,058,300
U.S. E.P.S. Orders to Foreign Manufacturers (Imports)					
Units					
kW					

Table 25/MANUFACTURE OF NUCLEAR REACTORS (50,000 kWe and Larger)

Customer	Completed	Scheduled as of January 1, 1986		Total Scheduled for Completion as of 1-1-86	New Orders Booked
	1985	1986	1987 and Later		1985
U.S. Electric Power Systems					
Units	8	14	26	40	–
kWe	9,804,000	15,804,000	28,718,000	44,522,000	–
Exports from U.S.					
Units	5	8	13	21	–
kWe	4,369,000	7,034,000	11,911,000	18,945,000	–
Total					
Units	13	22	39	61	–
kWe	13,453,000	22,838,000	40,629,000	63,467,000	–

Table 26/MANUFACTURE OF POWER TRANSFORMERS (501 kVA and Larger)

Customer		Shipped During 1985	Scheduled as of January 1, 1986							Total Scheduled for Shipment as of 1-1-86	New Orders Booked During 1985
			1986	1987	1988	1989	1990	1991	1992 and Later		
						501 to 10,000 kVA					
U.S. Electric Power Systems and U.S. Industrials	(Units	4,469	1,675	26	2	2	–	–	–	1,705	4,163
	(MVA	11,067	3,558	44	2	0	–	–	–	3,603	10,902
Exports from U.S.	(Units	15	56	–	–	–	–	–	–	56	70
	(MVA	17	124	–	–	–	–	–	–	124	142
TOTAL	(Units	4,484	1,731	26	2	2	–	–	–	1,761	4,233
	(MVA	11,083	3,682	44	2	0	–	–	–	3,728	11,043
						10,001 to 30,000 kVA					
U.S. Electric Power Systems and U.S. Industrials	(Units	541	276	5	3	7	–	–	–	291	582
	(MVA	16,030	6,698	165	120	333	–	–	–	7,316	15,096
Exports from U.S.	(Units	8	–	–	–	–	–	–	–	–	4
	(MVA	290	–	–	–	–	–	–	–	–	200
TOTAL	(Units	549	276	5	3	7	–	–	–	291	586
	(MVA	16,320	6,698	165	120	333	–	–	–	7,316	15,296
						30,001 to 100,000 kVA					
U.S. Electric Power Systems and U.S. Industrials	(Units	219	162	4	16	6	8	–	8	204	235
	(MVA	14,437	9,074	250	1,070	410	479	–	635	11,919	15,478
Exports from U.S.	(Units	1	1	–	–	–	–	–	–	1	2
	(MVA	110	167	–	–	–	–	–	–	167	292
TOTAL	(Units	220	163	4	16	6	8	–	8	205	237
	(MVA	14,547	9,241	250	1,070	410	479	–	635	12,085	15,770
						100,000 kVA and Larger					
U.S. Electric Power Systems and U.S. Industrials	(Units	76	34	7	8	7	1	2	14	73	70
	(MVA	32,691	13,676	3,385	2,929	2,606	784	1,673	4,396	29,449	23,561
Exports from U.S.	(Units	1	2	–	–	–	–	–	–	2	2
	(MVA	217	434	–	–	–	–	–	–	434	334
TOTAL	(Units	77	36	7	8	7	1	2	14	75	72
	(MVA	32,908	14,110	3,385	2,929	2,606	784	1,673	4,396	29,883	23,895
						Total (501 kVA and Larger)					
U.S. Electric Power Systems and U.S. Industrials	(Units	5,305	2,147	42	29	22	9	2	22	2,273	5,050
	(MVA	74,225	33,006	3,844	4,120	3,350	1,263	1,673	5,031	52,287	65,037
Exports from U.S.	(Units	25	59	–	–	–	–	–	–	59	78
	(MVA	634	725	–	–	–	–	–	–	725	967
TOTAL	(Units	5,330	2,206	42	29	22	9	2	22	2,332	5,128
	(MVA	74,859	33,731	3,844	4,120	3,350	1,263	1,673	5,031	53,012	66,004

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